EXHIBIT 19

UNITED STATES DISTRICT COURT
SOUTHERN DISTRICT OF TEXAS
HOUSTON DIVISION

IN RE ALTA MESA RESOURCES,) CASE NO.
INC. SECURITIES LITIGATION) 4:19-cv-00957

REMOTE VIDEOTAPED DEPOSITION OF
EDWARD FETKOVICH
NOVEMBER 1, 2023
9:03 a.m. ET

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Conducted Remotely Via Videoconference

[PAGES INTENTIONALLY OMITTED]

Q. Have you ever given an expert opinion on a financial question outside of this case?
A. I have not.
Q. Have you ever given an expert opinion on an accounting analysis outside of this case?
A. I have not.
Q. Did you -- did you calculate the impact of Alta Mesa's ESP usage on its free cash flow?
MS. GRAGERT: Let me see the question.
Okay. You can answer.
A. No, I did not.
Q. Okay. In your economic analysis, what did you use for Alta Mesa's cost of capital?
A. 10 percent.
Q. 10 percent? And how did you derive the 10 percent cost of capital?
A. That is what I have seen in some of their presentations. Again, that was what was in their ARIES database.
Q. Did your economic analysis account for the additional costs of operating the ESPs?
A. It did.
Q. It accounted for the cost of electricity?
A. It did.
Q. Did it account for the cost of repairs?

A. It did not. And the reason why -- the explanation on that is we ran the ES- -- we ran the economics for the duration that the ESP was in. When it was in -- when it was removed, the economics were terminated, for those that were removed.

Q. And what about the ones that were removed in 2019? Did you account for the cost of those removals?

A. We did not account for the cost of the removals. We could have, but we did not account for the cost of the removals.

Q. What about for the wells that were converted from gas lift to ESP and then reconverted to gas lift? Did you account for the cost of the additional installation of a gas lift?

A. At the end after the ESP was removed?

Q. Yes.

A. We did not, but I am aware of those costs.

Q. Did your economic analysis account for the negative effects on production from offset wells due to ESP usage?

A. In the economic analysis, it did not, but we were informed on the impact on the offsets. And of the 81 installations, I noted that I believed that there were three that had a -- an overall --

that had offset impact out of the 81.

Q. And how did you -- how did you reach that conclusion that only three of those 81 had offset impact?

A. Looking -- looking through the production plots that were for all the wells. I think that was in Appendix C. I would go through and look at all the wells in the pattern at the time that the ESP was installed and then looked at the offset performance to see if there was -- to see if there was any impacts.

And sometimes there was actually positive impact on the offsets where the ESP actually acted as a sump to pull water off offset wells. There were wells where the -- in some instances where what -- the production dropped. There are other wells where actually the decline of the offset wells became much shallower afterwards.

So there were a lot of information. There was a lot -- there were a lot of moving parts to that, but we did -- we did look at it. And I would say that we looked at the ESP installations on improved production and in wells where they were installed to improve production or wells that they installed for a frac hit.

There were of the 81, roughly -- so this is approximate. About half of those, give or take, were to improve production, and the other half, give or take, were for frac hits. If I subdivide those, it coincidentally turned out that approximately half in each category were involved with being installed in a pattern with multi-wells. The other half were actually installed in wells where they were the only wells in a section.

And therefore, those installations were critical because they -- by installing the ESP and restoring the production or improving the production, they protected the rights to the mineral owner. So they protected against drainage, which I thought was important.

Q. And did you include that benefit in your economic analysis?

A. Didn't. Did not.

Q. You talk about the 81 installations. Those are frac hits and what you call improved production. But that does not include any analysis of the installation in new wells, correct?

A. That is correct.

Q. And you're giving -- you offer no opinion about the economic impact of the installation of

those 21 ESPs in new wells. Is that correct?

A. That's correct. And the reason why is with the improved production of the frac hits, you had a before and after. You had an artificial lift before and an artificial lift after. Didn't know how to run the economics of the before. And that's the reason why. I mean, you -- there could be lots of questions about assumptions when there wasn't any basis for it. So that's -- that's why I didn't.

Q. Well, couldn't you -- couldn't you look at, sort of on an average basis for comparable new wells, develop a type curve for no ESP and a type curve for ESP and get a sense?

A. The answer to that is that -- that would create significantly more uncertainty than it creates certainty. There's -- if you look through those production plots, you can see that there's any -- if you look across all the wells, there's quite a variation in the production performance from the vari- -- from all the various wells. I wouldn't know how to do that.

Now, an observation was that, in general, the wells that I looked at that had an ESP installed in a new well, in general, those ESPs seemed to outperform the other wells.

So I am not sure how -- I -- there was a thought to do it, but it was like, I don't -- I'm not sure how I would do it, how I -- how I could do it and be able to sit here and defend, you know, exactly the process, the thought process that would go into analyzing -- analyzing that.

But the wells -- the new wells that had ESPs, if you look through those plots, generally the production character of those wells was very smooth and monotonic in their performance compared to the gas lift wells which had a lot more noise with them.

So I didn't see -- again, to answer your question, I didn't see a solid basis for creating a "not" case.

Q. Did you look at the impact of ESPs in new wells on wells offset to those new wells?

A. There isn't any way to make that assessment. I don't -- I don't know how to make that assessment.

Q. Could you calculate the costs associated with installing and operating ESPs in the new wells?

A. Well, the cost of installing, yes. We had that information. And the cost of operating, we had -- we had that information.

Q. So -- but you did not provide in your

report, you did not provide the cost of the new well ESPs, correct?

A. That is correct, for all the reasons that I stated.

Q. And did you calculate the cost of the new well installations during your -- during the course of your work?

A. No, I did -- I just did not make an effort on those wells.

Q. If there's 21 of them and we use the gross capex figure of $453,000 per install, that gets us, you know, just rough cut it, a gross cost of about $9.5 million, right?

MS. GRAGERT: Objection.

A. Okay.

THE REPORTER: I'm sorry. What was the answer?

MR. BRODEUR: He said "okay."

THE REPORTER: Okay.

Q. Is it true that when a well is frac hit -- just take a step off of the ESPs just for one second. When the well is frac hit, the production can drop to minimal or even zero, correct?

A. That is correct.

Q. And then is it true that sometimes a

frac-hit well can return to its prior or close, return to close to its prior production curve over time without the intervention of an ESP?

A. Yes. And I -- and I actually -- I actually state that in my rebuttal report. I actually state that along with examples. I stated there are many examples where that occurs. The problem is you don't know because I also show a number of examples where a frac-hit well that remained on gas lift never returned to its pre-frac hit rate or never returned to any hydrocarbon rate at all. And that is the unknown.

The problem is, especially with a frac-hit well, if I've got a -- for the sake of round numbers only, if I have a $4 million investment and it gets knocked off online, gets knocked off-line where it's not producing anything, that's a problem. If I can make a few-hundred-thousand-dollar investment and get that well back online, that's -- that's important, because I have a significant investment that is not available to me to produce.

Q. When you were calculating the incremental additional oil for the ESPs in the frac-hit wells, did you account for the possibility that the frac-hit well would have recovered somewhat on its

own without the ESPs?
A. I did not. I -- to answer your question, I assume -- the rate that it was producing at before, if it was zero, I assumed it was zero. If it was producing a -- some number, we just attempted to forecast that out or I forecasted that out and said that was the -- that was the base.
So there is not -- and honestly, some of that's why I didn't go into the economics at the beginning because it becomes -- you know, there's lots of questions you can ask. But then for this exercise, I went through based on commentary that I saw. "Well, we need to make an estimate. We will go through and make an assessment, and then we'll answer questions around that assessment."
So that was the -- that was the thinking for putting it in the rebuttal because the commentary was around the fact that there was no basis and no reason to do it, of which I disagree with.
Q. Yeah. So is it a fair assumption that at least some of those frac-hit wells would have recovered somewhat on their own without the ESP?
A. I have no way to answer that.
Q. If it is true that some of those frac-hit

wells would have recovered somewhat on their own without the ESPs, does that mean that your analysis somewhat overstated the incremental oil production due to the installation of the ESP?

A. If what you say -- if what you say occurs, then that would be a true statement.

Q. If we look at page 24 of your rebuttal report.

A. Okay.

Q. All right. And I'm looking at subsection 2, and I see you have a bulleted breakdown of the frac-hit wells and the production wells.

Do you see that?

A. I do see that, yes.

Q. And based on your analysis, are you saying that there was a $7.18 million present value benefit to ESP installations in the frac-hit wells?

A. That's -- that is what I'm saying, yes.

Q. And then in the -- in the improved production category, that's 45 wells, correct?

A. That's correct, yes.

Q. And you're saying that the economic impact of the well -- the ESP installs and the improved production wells in total was $.836 million in present value. Is that -- am I understanding that?

A. For the improved production, yes.

Q. Okay. And then so that's 36 frac-hit wells, 45 improved production wells. And as we've discussed, there's no analysis on the 21 new well installations, correct?

A. Correct.

Q. Okay. And the results that are shown in this -- this little bulleted summary, that's based on -- the costs in that are based on the AFEs? Is that correct?

A. That is correct. It's based on the AFEs.

Q. Are you aware of testimony in this case that -- or any evidence in this case that Alta Mesa understated certain costs in some of their AFEs?

MS. GRAGERT: Objection.

A. I'm not aware. I'm not aware of that.

Q. Do you know whether the AFEs would include the operating costs of the ESPs, including electricity?

A. No, the AFEs would not. That would have been in the ARIES economics case.

Q. And did you -- did you -- so when you say you based it on the AFE, did you take that number of the AFE and then did you add the cost of electricity on top of that?

A. No. So what happened is the cost to install is a capital cost. Okay? That's an up-front capital cost. The cost to operate is an operating cost that's -- that's different.

What we did, because Alta Mesa did not provide significant detail on well-by-well-by-well operating costs, we used the ARIES economics database was -- that -- and the way they were set up at the end of 2017. And what they had in there was a average cost to operate a well. Okay? And so what we did was we assumed that that operating cost would be in force or in effect had the well remained on gas lift.

When -- for the case where -- for the part of the case that assumed the ESP install, we doubled that cost. And we felt like that was actually probably really conservative, on the high side, to double the -- to just take that cost and double it. It should have been more like 50 percent, but we felt like that was a reasonable thing to do.

So to understand the way we ran the economics, if we had a well that was on improved production, we saw how it was trending before the ESP was installed; we forecasted that production to get a base case. We had those -- we had those

operating costs I just mentioned. That would be like the negative one case in ARIES. And then for the positive one case, we had the capital cost to install the -- to install the ESP.

And then the production history for that install was the production history, right? We didn't do anything to finesse that. It was the production history. And the economic case lasted for as long as the ESP was installed.

If the ESP was never removed, then we simply ran the case to the end of the available data that we had, which was the February of 2020. And that's how we ran it.

MS. GRAGERT: Counsel, you've got about 30 minutes left.

MR. BRODEUR: Well, I'm not sure about that, but it should be enough.

Q. The -- did you -- did you project incremental oil production out for the life of the wells if the ESP was not removed?

A. No. We stopped -- if the ESP was not removed, we just -- we stopped at the ca- -- at the end of available history, which for us was February of 2020.

Q. Let's go to Appendix A of your rebuttal

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